Reliability Must-Run Analysis

2003–2005

January 31, 2003
APS Transmission Planning
APS Resource Planning

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APS Reliability Must-Run Analysis 2003-2005

I. Executive Summary

This report documents the study methodology, results, and conclusions of Arizona Public Service Company's (APS) Reliability Must-Run (RMR) Analysis for 2003 through 2005. This analysis was conducted in response to the Arizona Corporation Commission's (ACC) Second Biennial Transmission Assessment (Assessment) and Decision No. 65476 (December 19, 2002). As required by the Assessment, the 2003 RMR Analysis covers three years. The 2004 RMR Analysis will cover 10 years.

If a city or load pocket must be served by local generating units at certain peak times, then those units are designated as "reliability must-run" or RMR units. In APS' service territory there are two major areas where load cannot be served totally by power imported over transmission lines – the Phoenix metropolitan area and Yuma. The cost of using must-run units can be measured by the difference between generation costs with the transmission limit and costs without the limit. This report looks at and compares the cost of serving these two areas with and without the existing transmission constraints.

This report concludes that for the Phoenix metropolitan area, the cost of RMR with the transmission limit does not at present outweigh the cost of transmission improvements to remove the limitation. For Yuma, the report shows that the addition of a 500/69 kV transformer at the North Gila substation could be a cost-effective measure to improve transmission import capacity. Environmental effects for both areas with and without transmission constraints are also documented in this report.

A. Study Overview

The existence of transmission import limited areas is not uncommon in the United States, and particularly in the West where load centers are generally separated by long distances. APS has transmission import-limited areas in Phoenix and Yuma. An import area is transmission limited when all load cannot be served solely by importing resources over local transmission lines, thus requiring some use of local generating units to reliably meet peak load.

The two transmission import-limited areas in APS' system were studied to determine:

- The system simultaneous import limit (SIL), which is the maximum amount of capacity that can be reliably imported into an area with no local generation;
- The maximum load serving capability (MLSC), which is the total load that can be reliably served from imports and from local generation;
- Annual RMR conditions, including magnitude of load in excess of the SIL and number of hours the load exceeds the SIL; and
- Estimated economic impacts of the import limits.

Additionally, transmission alternatives were studied to compare the costs of mitigating the annual RMR conditions with the potential benefits of such mitigation.

The Phoenix area is a tight network of APS and Salt River Project (SRP) load, resources, and transmission facilities. Because the Phoenix system is highly integrated, the import limits must be determined for the combined area. This analysis was coordinated with SRP personnel, who had significant involvement in the study and were helpful in the overall analysis. The Western Area Power Administration (WAPA) participated in the study because their transmission facilities interface with the Phoenix network and also provided helpful comments.

After the combined import limit (SIL) for the Phoenix area was determined, RMR conditions were evaluated for APS based on APS' share of the combined import limits, APS' Phoenix-area load, and Phoenix area local generation, which includes generation owned by APS, SRP and Pinnacle West Energy Corporation (PWEC).

The Yuma area, which has a summer peak demand of approximately 300 MW, is served by an internal APS 69-kV sub-transmission network containing all of the load in the import-limited area. There are external ties to WAPA and the Imperial Irrigation District (IID), as well as a bulk power interface with the Palo Verde-to-North Gila transmission system. This analysis was coordinated with the WAPA Phoenix office to ensure accurate modeling.

B. Summary of Results

Results of the analysis for the three years of the study, which are summarized in the following tables, assume that present plans for system improvements are completed on schedule.

The following table summarizes the estimated RMR effects and costs for APS load in the Phoenix area.

Table ES1
Phoenix-Area RMR Effects and Costs for APS Load

Year	SIL[1] (MW)	Peak Demand (MW)	Max RMR[2] (MW)	RMR[3] Hours	RMR Energy[4] (GWH)	RMR Energy (% of total)	RMR Cost[5] ($M)
2003	3621	4456	835	518	170	0.9	0.03
2004	3658	4614	956	590	211	1.0	0.4
2005	3709	4733	1024	656	243	1.1	0.7

The following table summarizes the estimated RMR effects and costs for load in the Yuma area.

Table ES2
Yuma Area RMR Effects and Costs for APS Load

Year	SIL[1] (MW)	Peak Demand (MW)	Max RMR[2] (MW)	RMR[3] Hours	RMR Energy[4] (GWH)	RMR Energy (% of total)	RMR Cost[5] ($M)
2003	164	308	144	3184	143	10.2	1.5
2004	164	312	148	3512	162	11.3	1.3
2005	164	324	160	3834	186	12.4	1.5

Table Key:

[1]**SIL** – System Simultaneous Import Limit is the maximum amount of capacity that can be reliably imported into the area with no local generation operating.

[2]**Max RMR** – The amount of local generation required to meet the area peak demand (Peak Demand minus SIL).

[3]**RMR Hours** – The number of hours that the area's demand exceeds the SIL, thus requiring the use of local generation to meet load.

[4]**RMR Energy** – The annual energy required to be met by local generation (in excess of the SIL).

[5]**RMR Cost** – The difference in annual generation cost with and without the transmission limitation.

In addition to APS local generation, there are SRP, PWEC or other resources that can be used to meet the RMR requirement. The RMR requirements for non-APS generation are determined by including the APS local generation minus local reserve requirements with the SIL and subtracting that number from the estimated peak demand.

The table on the following page summarizes the estimated non-APS RMR requirements for APS load in the Phoenix area.

Table ES3

Phoenix-Area Non-APS RMR Requirements for APS Load

Year	SIL plus APS Local Generation[1]	Peak Demand (MW)	Non-APS Max RMR (MW)	Non-APS RMR HOURS	Non-APS RMR Energy (GWH)
2003	4091	4456	365	152	23
2004	4128	4614	486	200	42
2005	4179	4733	554	230	55

The following table summarizes the estimated non-APS RMR requirements for load in the Yuma area.

Table ES4
Yuma Area Non-APS RMR Requirements for APS Load

Year	SIL plus APS Local Generation[1]	Peak Demand (MW)	Non-APS Max RMR (MW)	Non-APS RMR HOURS	Non-APS RMR Energy (GWH)
2003	233	308	75	836	21
2004	233	312	79	962	27
2005	233	324	91	1104	34

[1]SIL plus APS local generation minus reserve requirement (190 MW for Phoenix, 70 MW for Yuma)

Local generating units are dispatched based on cost, along with the rest of APS' resources. Thus, most of the RMR hours shown above are "in the money" when dispatched. However, the presence of a transmission constraint may require local generation to be dispatched "out of the money." This report considered all Phoenix-area transmission limitations and generation resources in determining the overall RMR situation. The economic impact of RMR can be seen from the following tables.

The following table summarizes the estimated total number of hours that APS local Phoenix generation must run out of economic dispatch, the amount of energy that is produced out of economic dispatch and the associated cost.

Table ES5
APS Phoenix-Area RMR Outside Economic Dispatch

Year	Hours outside economic dispatch	Energy outside economic dispatch (GWH)	RMR Cost ($M)
2003	32	7	0.03
2004	146	43	0.4
2005	174	44	0.7

The following table summarizes the estimated total number of hours that APS local Yuma generation must run out of economic dispatch, the amount of energy that is produced out of economic loading and the associated cost.

Table ES6
APS Yuma Area RMR Outside Economic Dispatch

Year	Hours outside economic dispatch	Energy outside economic dispatch (GWH)	RMR Cost ($M)
2003	1066	54	1.5
2004	974	49	1.3
2005	1196	56	1.5

C. Report Conclusions

Phoenix-Area Conclusions

1. During the summer, APS Phoenix-area load is expected to exceed the available transmission import capability for approximately 500 hours in 2003 and 650 hours in 2005. However, these hours represent only one percent of the annual energy requirements for APS' Phoenix area.

2. From a total Phoenix load, transmission, and resources viewpoint (APS, SRP, and PWEC), import limits are expected to cause APS local generation to be dispatched out of economic dispatch order for 32 hours in 2003, 146 hours in 2004, and 174 hours in 2005.

3. The estimated annual economic cost of Phoenix-area generation required to run out of economic dispatch order is estimated to be $720,000 in 2005, compared to a cost of approximately $16 million to relieve 452 MW of the Phoenix area's transmission constraint. Thus, the transmission alternative currently is not cost justified.

4. All Phoenix-area transmission and local generation are necessary to reliably serve all Phoenix-area peak load.

5. In capacity terms, APS will require from 365 MW in 2003 to 554 MW in 2005 of non-APS resources within the Phoenix area to serve the APS Phoenix-area load. These resources could be supplied from non-APS local generation (including PWEC West Phoenix Units 4 and 5, SRP Phoenix-area generation, or newly constructed local generation) or from remote generation delivered to APS using SRP Phoenix-area import capability.

6. Non-APS generation outside of the Phoenix load area (or inside the Phoenix load area when serving load outside) has the following impact on Phoenix-area import capability, measured as a percent of additional MW of import capability to MW of output:

   West Phoenix Units 4 and 5……………………134%

   Sundance……………..………………………. 35%

   Desert Basin……….………………………… 24%

   Hassayampa Area……………………………… 0%

   Panda Gila River………………………………. 0%

7. Removing the transmission constraint would reduce total Phoenix-area air emissions by the following average annual amounts over the 2003-2005 period.

Table ES7
Phoenix-Area Air Emissions Reduction

Pollutant	Avg. Reduction (tons/year)	Reduction of Phoenix Area Emissions (% of total emissions from all sources)
VOC	1.0	0.001
NO_x	29.5	0.049
CO	5.5	0.002
PM_{10}	1.8	0.002

8. Removing the import restriction into the Phoenix area reduces the APS local generation capacity factor from 1.4% to 0.9%.

Yuma Area Conclusions

9. The Yuma-area load is expected to exceed the available transmission import capability for approximately 3,200 hours in 2003 and 3,800 hours in 2005, although the amount of total load in the Yuma area is only approximately 300 MW.

10. From a total Yuma load, transmission, and resources viewpoint (APS, IID, and YCA), the import constraint could cause APS Yuma generation to be dispatched out of economic dispatch order for approximately 1,070 hours in 2003, 975 hours in 2004, and 1,200 hours in 2005.

11. The addition of a second 500/69 kV transformer at the North Gila station in the Yuma area will be further studied. Preliminary analysis shows that installation of this transformer significantly reduces Yuma-area RMR. Preliminary study results show potential savings in energy costs from removing the constraint of approximately $1.4 million per year for the years 2003 through 2005. The cost to install a second 500/69kV transformer is estimated to be $3.5 million.

12. All existing Yuma-area transmission and generation resources are necessary to reliably serve the Yuma-area load.

13. In capacity terms, APS will require from 75 MW in 2003 to 91 MW in 2005 of non-APS resources in the Yuma area to serve the APS Yuma-area load. These resources may be supplied from the 75 MW IID steam generator at the Yucca substation, the 53 MW YCA co-generator near the Riverside substation, or future generation/transmission construction in the Yuma area.

14. Removing the transmission constraint could reduce total Yuma-area air emissions by the following average annual amounts for the period 2003-2005.

Table ES8
Yuma Area Air Emissions Reduction

Pollutant	Avg. Reduction (tons/year)	Reduction of Yuma Area Emissions (% of total emissions from all sources)
VOC	9.5	Unavailable
NO_x	154	Unavailable
CO	33	Unavailable
PM_{10}	6.5	0.003

15. Removing the import restriction into the Yuma area could reduce the APS Yuma generation capacity factor from 4.4 percent to 0.1 percent.

D. Report Organization

This report is organized in eight sections. Section I provides an executive summary of the report. Section II provides general background information of the study requirements, an overview of RMR, and describes the study methodology. Section III describes the Phoenix area, the nature of the import limit, the resulting import limits for 2003 through 2005, and the impact of various generators in and around the Phoenix area on the import limit. Section IV provides a similar discussion of the Yuma area. Section V describes the RMR conditions such as number of hours, maximum capacity, and annual energy for the Phoenix and Yuma areas. Section VI provides results of the economic analysis of the Phoenix and Yuma area RMR conditions performed utilizing a regional planning model (GE MAPS) and emissions impact. Section VII identifies and analyzes preliminary transmission alternatives to mitigate the import limits of the Phoenix and Yuma areas. Finally, Section VIII lists the conclusions of the analysis.

II. INTRODUCTION

A. Background of Study Requirement

Like all large electric utilities, APS has historically relied on both transmission to deliver remote generation into its load centers as well as local generation to reliably serve its customers. Generation located close to load results in reduced losses, lower capital expenses for transmission infrastructure, and enhanced reliability and operating flexibility. However, due in part to environmental, economic, and fuel availability considerations, large base-load thermal generators have typically been located away from the load centers while smaller but less efficient intermediate and peaking units — with lower capacity factors — were located within the load centers.

In the past, vertically integrated utilities such as APS managed the siting and construction of both generation and transmission resources needed to serve their customers. Electric systems were designed based on a detailed integrated resource planning process used to evaluate the appropriate balance of generation, transmission and demand-side resources. Interconnections with neighboring systems were primarily intended to improve system reliability and lower the costs of reserves, by allowing for sharing of capacity reserves by multiple systems. Each utility's system was primarily designed to accommodate that utility's resources and that utility's load.

The Commission's Second Biennial Transmission Assessment requires "any [Utility Distribution Company] that currently relies on local generation, or foresees a future time period when utilization of local generation may be required to assure reliable service for a local area, [to] perform and report the findings of an RMR study as a feature of their ten year plan filing with the Commission in January 2003 and 2004." The Assessment requires that the RMR study filed in January 2003 evaluate RMR conditions through the 2005 summer peak. The January 2004 RMR study will cover a 10-year period.

B. Overview of RMR

Local "load pockets" are areas that do not have enough transmission import capability to serve all load in the area solely by importing remote generation over local transmission facilities. For these areas, during peak hours of the year, local generation is required to serve that portion of the load that cannot reliably be served by transmission imports. This local generation requirement is often referred to as Reliability Must-Run or RMR generation. In these areas, during peak conditions, load is served by a combination of importing remote generation over transmission lines and operating local generation.

The maximum load that can be served in a load pockets with no local generation operating — in other words, the maximum load that can be served solely by importing remote generation — is referred to as the system Simultaneous Import Limit (SIL). The SIL is established through technical studies by ensuring that:

- With the local load at the SIL and no local generation operating there are no transmission system normal operating limit violations of thermal loading or voltages (N-0), and
- Under all single contingency outage events there are no emergency operating limit violations of thermal loading or voltages, and no system instability (N-1).

C. Study Methodology

Import limit analysis was performed for the Phoenix and Yuma areas. See Appendix A for power flow results. The import limit area or load pocket is defined as that load which, when increased, would increase the severity of the limiting contingency. For example, load in Flagstaff has no impact on the severity of the limiting contingency for the Phoenix import limited area, and therefore Flagstaff is not included in the Phoenix load pocket. In contrast, downtown Phoenix load does impact the severity of the limiting contingency and therefore is included in the load pocket. All area contingencies known to result in system stress were evaluated to determine the critical contingency for the area. Import limits were determined by contingency conditions of thermal loading at the emergency rating of a facility, steady state voltages at the emergency voltage limit, and system instability including voltage instability.

Import limits were determined for the Phoenix and Yuma areas with no local generation operating, with maximum local generation operating, and sufficient points in between to determine curves which define import limits at all load levels. This methodology was applied to studies of the Phoenix area, which is constrained by voltage instability. For the Yuma studies, the limitations are primarily post-disturbance thermal constraints. Generator sensitivities were performed to determine the relative impact of various generators on the import limits.

From each year's forecasted peak load and historical daily load cycles, the annual RMR conditions were determined including magnitude of local load, both demand and energy, expected to exceed the SIL and the annual hours for which local load is expected to exceed the SIL.

An economic analysis was performed in each area for each year using the GE MAPS production-costing model to determine the cost of the import limits. Local generating units not owned by APS were modeled based on unit commitment and economic dispatch principles while observing any known operating and contractual constraints. GE MAPS is a regional generation and transmission simulation model and is discussed in more detail in Appendix B to this report.

Several transmission alternatives to relying on local generation to meet all loads in excess of the area SIL were identified and then studied with the GE MAPS model to determine impact on SIL and other RMR conditions. The production cost analysis was then repeated to determine the value of these transmission alternatives in mitigating the RMR conditions.

D. Determination of SIL and RMR Conditions

In this analysis, assessments of the SIL and RMR conditions for the Phoenix area and the Yuma area were performed for the years 2003, 2004 and 2005. Base case and contingency power flow, stability, and voltage stability analyses were performed to determine import limitations. The initial starting case was based on a 2002 WECC full loop base case in GE Power Flow format. This base case models the entire Western Interconnection's transmission system and was reviewed and then updated to represent expected loads and system configuration for 2003, 2004 and 2005. All cases were coordinated between APS, SRP, Tucson Electric Power Company (TEP), and WAPA to capture the most accurate expected operating conditions for the Arizona transmission system.

III. PHOENIX LOAD POCKET

A. Description of Phoenix Area

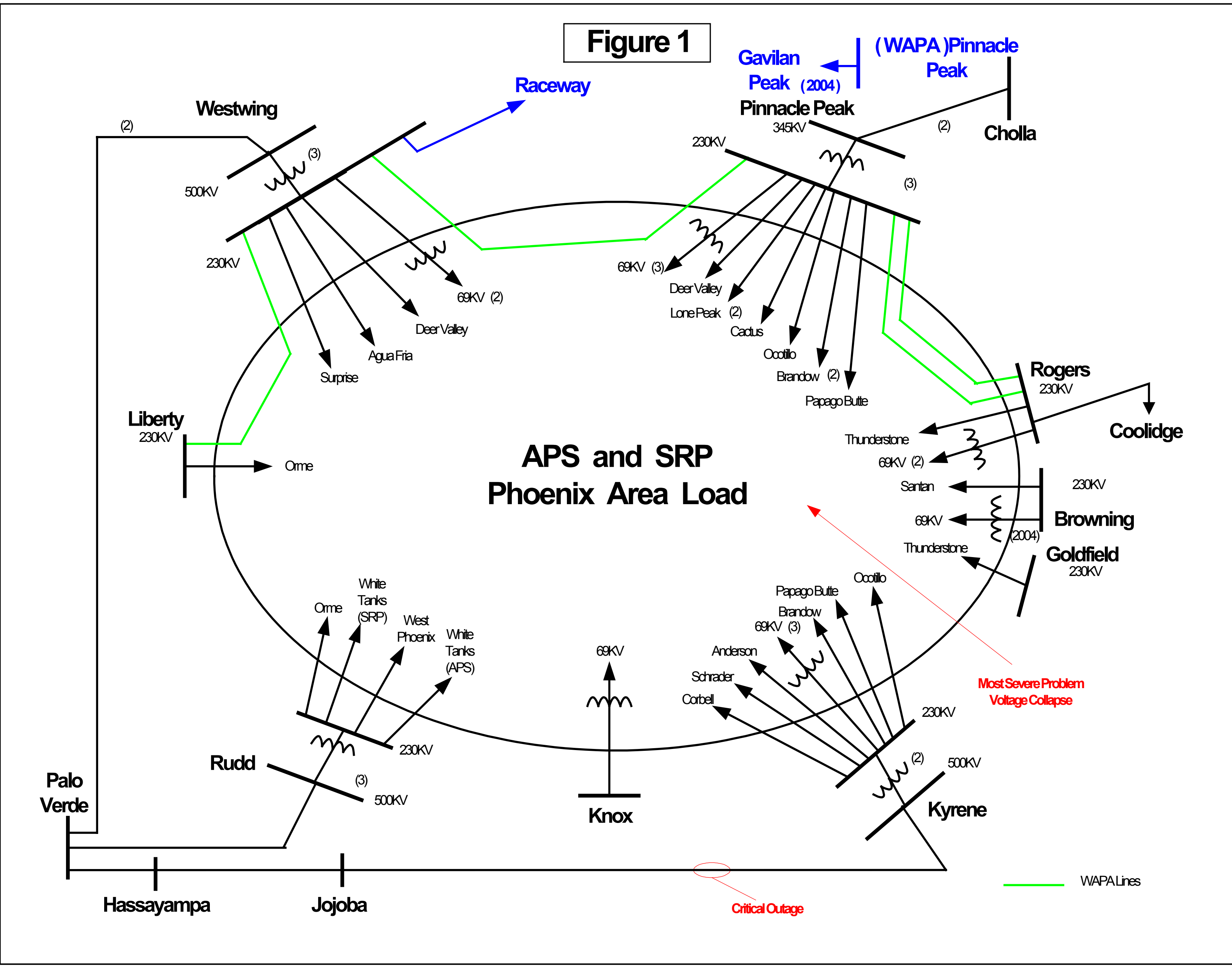
By summer 2003, the Phoenix area — which consists of both APS' and SRP's integrated network — will be served primarily from four major Extra High Voltage (EHV) substations: Westwing, Pinnacle Peak, Kyrene and the new Rudd substation. These four EHV stations form the "cornerstones" of an extensive internal network of 230 kV transmission lines that constitute the high voltage energy delivery system within the Phoenix load area. Figure 1 shows the major EHV delivery points and the 230 kV transmission lines and transformers that are used to determine the Phoenix-area load. Energy flows into the EHV delivery points from the EHV transmission lines and then is stepped down to 230 kV and transmitted into the load center via the 230 kV transmission lines. The Phoenix-area load is determined by the flows on these 230 kV lines and 230/69 kV transformers out of the EHV delivery substations and into the Phoenix load area. This is the load that significantly impacts the severity of the limiting contingencies because, for outages of EHV sources to the EHV delivery points and for outages of the 230 kV lines into the load center, the energy flow is transferred to other EHV lines to the EHV delivery points, or to other 230 kV lines into the load center.

In the summer of 2003, APS will serve some northwest Phoenix-area load from the Raceway substation, which has been built as an interconnection to the WAPA Westwing-to-Waddell 230 kV line. Because this line has no interconnections with other Phoenix area 230 kV lines, this load does not significantly impact the contingency response of the Phoenix area and is therefore not included in the Phoenix-area load determination. Likewise, in 2004 APS will interconnect the Gavilan Peak substation into WAPA's Pinnacle Peak-to-Prescott 230 kV line and load served from this substation is not included in the Phoenix-area load determination.

SRP and the City of Mesa (which serves approximately 80 MW of load in downtown Mesa out of a total Phoenix-area load of approximately 10,000 MW) share the 230 kV and 69 kV buses at the Rogers substation. The Rogers substation is interconnected at 230 kV with two WAPA transmission lines. SRP subtracts the City of Mesa load from the Phoenix-area load calculation but does not attribute any RMR generation responsibility to the City of Mesa. APS and SRP will reassess the treatment of the City of Mesa load and other area loads in the Phoenix-area load calculation for future years as part of the next RMR analysis due January 2004.

WAPA owns and operates several 230 kV transmission lines that encircle the Phoenix-area network. These lines add support and contribute to the total Phoenix-area import capability — as do all of the other lines in the Arizona transmission system. As shown in Figure 1, however, with the exception of Mesa there is no load directly served from these WAPA transmission lines. Thus, if the WAPA transmission lines were included in the Phoenix-area load calculation, the only additional load and import would be the losses on these lines. Because nothing would change in the model, the analysis and results would not change and the additional load from the losses would be exactly offset by an increase in import equal to the losses. Therefore, including or excluding the WAPA transmission lines in the Phoenix area does not affect either the SIL or MLSC.

Phoenix Area Load



In performing the Phoenix area studies several planned projects were added to reflect transmission system upgrades for the next three years:

<u>2003 Projects</u>

- Four Corners-Shiprock 230 kV line converted to 345 kV
- White Tanks 2nd 230/69 kV, 280 MVA transformer addition
- Rudd 500 kV substation and three 500/230 kV transformers
- Palo Verde-Rudd 500 kV line
- Rudd 230 kV substation
- West Phoenix-White Tanks 230 kV and Orme-White Tanks 230 kV lines looped-in to Rudd 230 kV substation
- West Phoenix CC#5 525 MW generation addition
- Re-conductor West Phoenix-Lincoln Street 230 kV line

<u>2004 Projects</u>

- Gavilan Peak substation connected to Pinnacle Peak-Prescott 230 kV line
- Reach 2nd 230/69 kV transformer addition
- Browning 230/69 kV, 280 MVA transformer addition

<u>2005 Projects</u>

- Cactus 3rd 230/69 kV transformer addition
- Surprise 2nd 230/69 kV transformer addition
- West Phoenix 3rd 230/69 kV transformer addition
- Thunderstone 2 new 230/69 kV, 280 MVA transformers addition
- Alexander 69 kV 46mvar capacitors addition
- Santan 825 MW generation addition

B. Phoenix Area Critical Outages

The analysis determined that the critical single contingency for the Phoenix load area is the loss of the Jojoba-to-Kyrene 500kV transmission line. The loss of this major 500 kV line to the Phoenix area results in significantly higher flows on the remaining transmission lines and causes a large increase in reactive power (Var) losses in the transmission network. The increase in Var consumption results in insufficient Vars for voltage support in the load area. Consequently, this condition creates low voltages in the system and makes the area deficient in reactive power. The system is constrained by voltage instability.

The voltage stability analysis was performed using Q-V analysis on the most reactive deficient buses in the Phoenix area. These buses were the Kyrene 500 kV, Kyrene 230 kV, Westwing 230 kV, and the Pinnacle Peak 230 kV buses.

C. Phoenix Area – SIL for 2003, 2004 and 2005

Analysis of the Phoenix-area transmission network resulted in area import limits based on the voltage stability limits discussed above. Operation of the Phoenix system within these limits ensures that the area does not experience voltage instability after a critical contingency. Voltage instability is characterized by a progressive fall in voltage magnitude at a particular location of the power system that may spread throughout the network causing a complete area voltage collapse and blackout.

To determine APS' SIL for the Phoenix area, the combined APS and SRP Phoenix-area import limits were first determined. The APS share of the import limit was then determined based on the allocation factor between APS and SRP. The combined and APS allocated SIL for the years 2003 through 2005 are outlined in Table 1.

Table 1
2003 – 2005 Simultaneous Import Limit

Year	Combined SIL (MW)	APS SIL (MW)
2003	8,557	3,621
2004	8,632	3,658
2005	8,733	3,709

Phoenix-area import limits across various load levels are shown in Figures 2, 3 and 4.

Figure 2

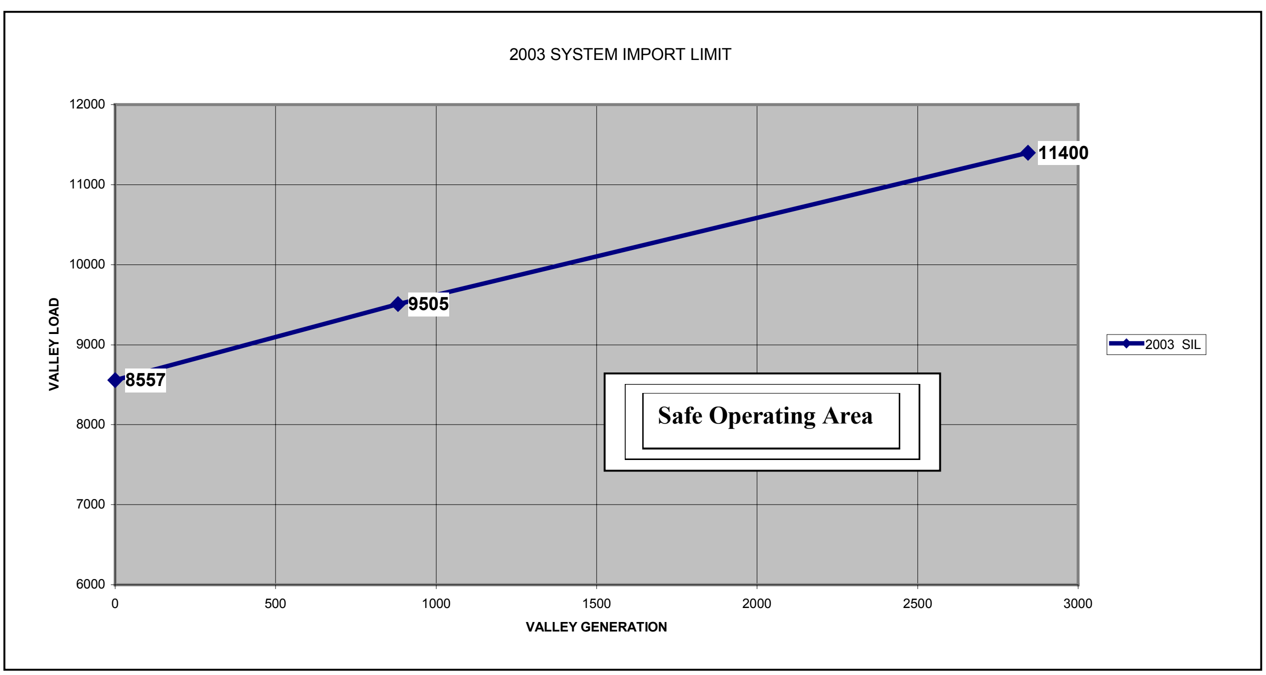


Figure 3

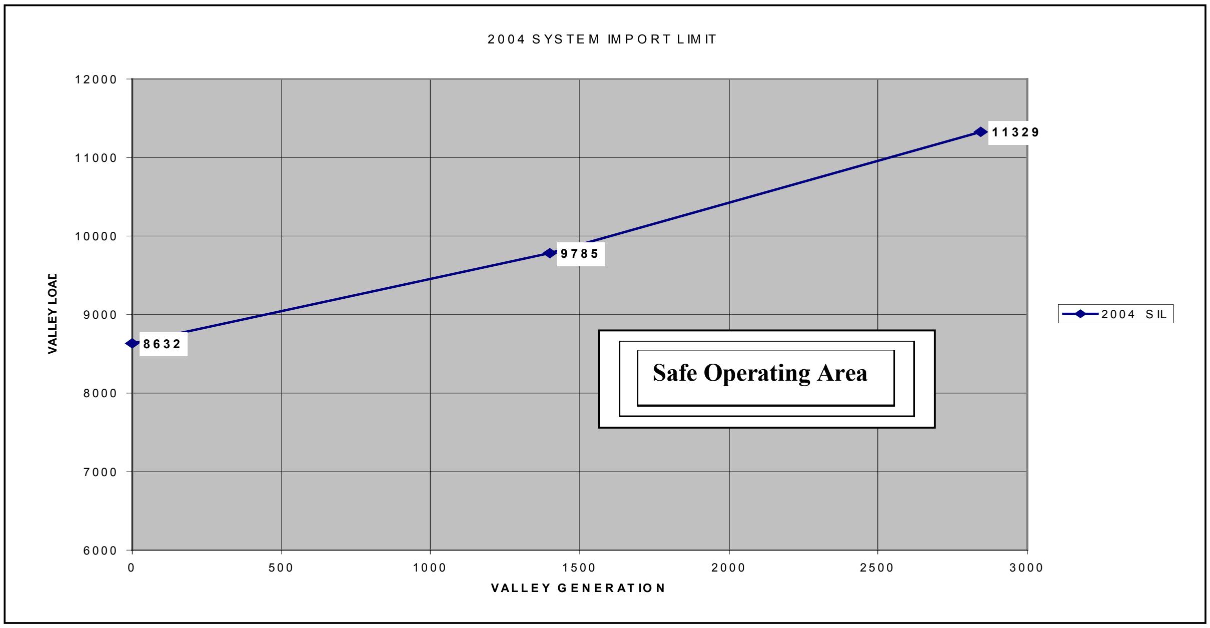
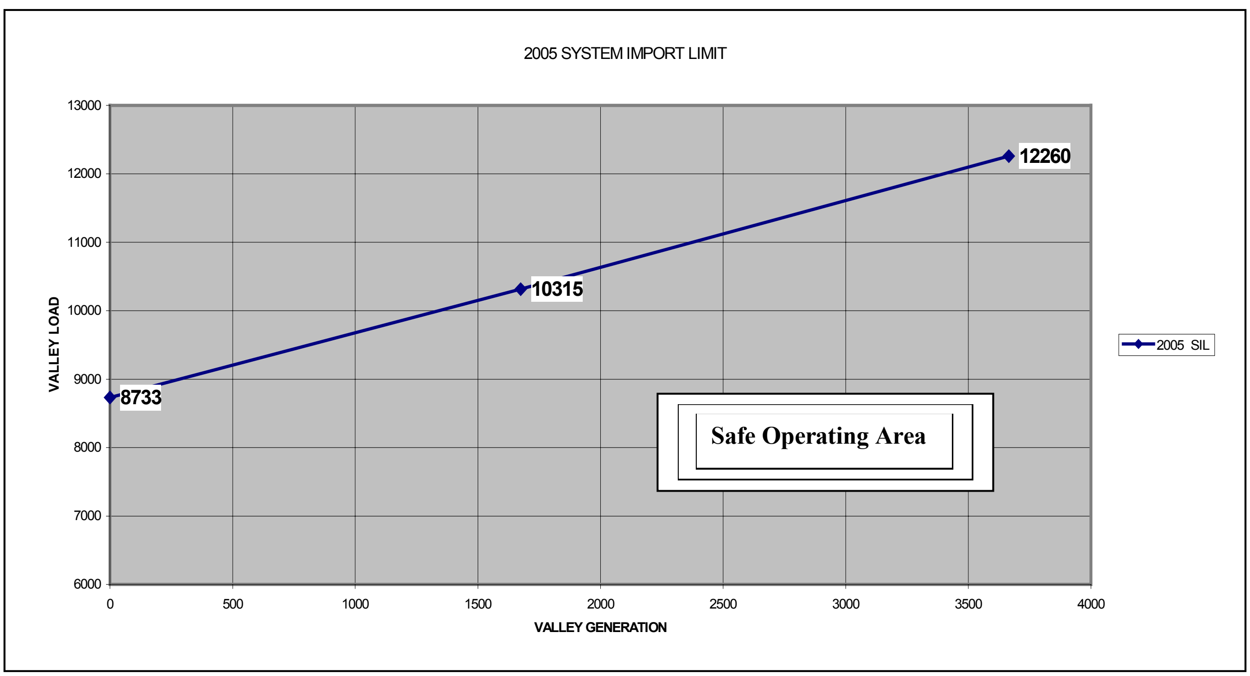


Figure 4



D. Generation Sensitivities

APS also conducted sensitivity analyses of generation impact on load-serving capability. The following table provides the results of these analyses for units that are both within and outside the Phoenix area.

Generation sensitivities inside the Phoenix area are listed in Table 2.

Table 2
Generation Sensitivities Inside Phoenix

Generation Source Increase by 100 MW	Load Serving Capability Increase (MW)
Agua Fria Generation	110
Kyrene Generation	147
Ocotillo Generation	141
Santan Generation	123
West Phoenix Generation	134

Generation sensitivities outside of the Phoenix Metro area are listed in Table 3.

Table 3
Generation Sensitivities Outside Phoenix

Generation Source Increase by 100 MW	Load Serving Capability Increase (MW)
Sundance Generation	35
Desert Basin Generation	24
Hassayampa Area Generation	0
Panda Gila River Generation	0

The results indicate that generators within Phoenix are more effective in increasing load-serving capability.

IV. Yuma Area

A. Description of Yuma Area

Currently the Yuma area is served from three transmission sources:

- APS' North Gila 500/69 kV substation, which is located east of Yuma. Two 69 kV lines extend west and southwest from this substation into Yuma to serve Yuma area load. A third 69 kV interconnects into WAPA's Gila substation.
- WAPA's Gila 161/69 kV station, which is also located east of Yuma. From this station, APS has one 69 kV line into the Yuma load area and one 69 kV tie to APS's North Gila substation.
- APS' Yucca 69 kV station, which is located on the west side of Yuma near the Colorado River. APS local generation is located at this station, along with three 69 kV lines into the load area. The IID 75 MW steam-generating unit is also located at this substation.

Figure 5 shows the transmission system and the metering points for the Yuma area load pocket.

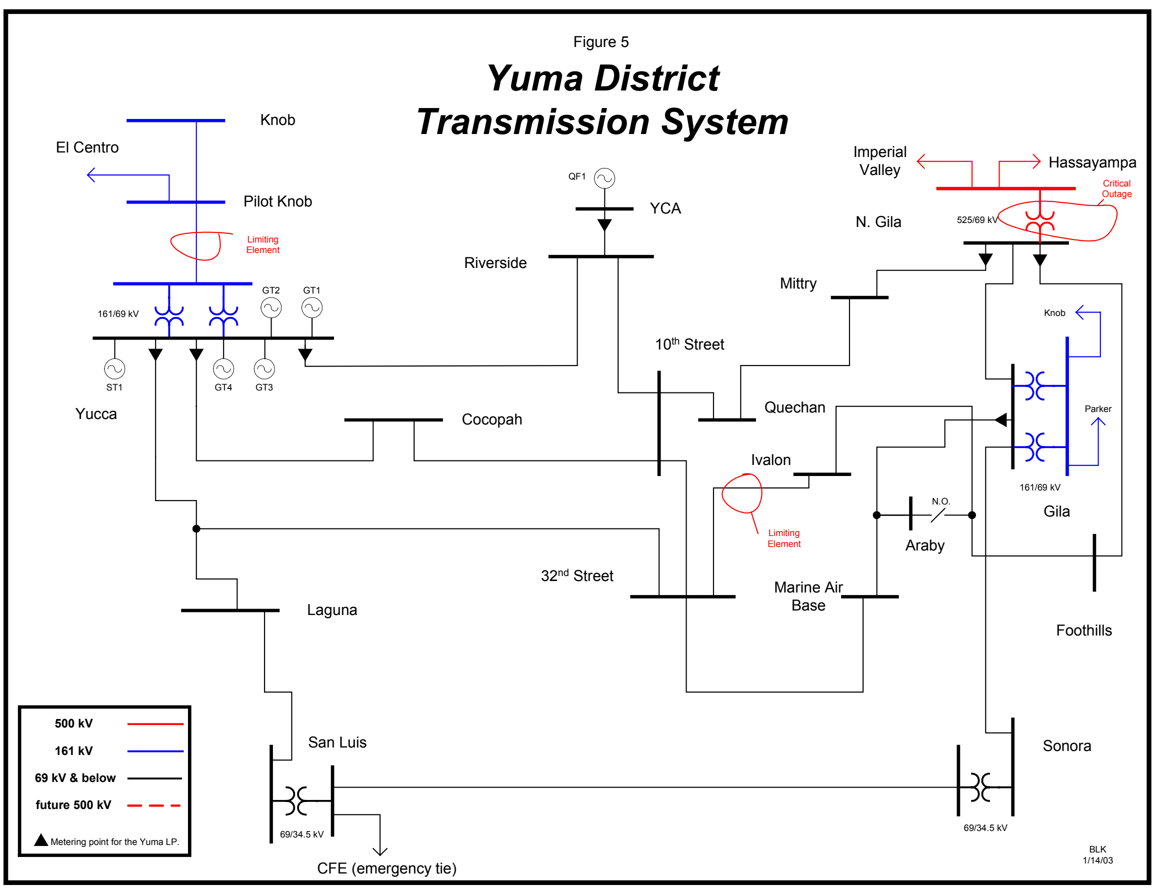


Figure 5
Yuma District Transmission System

B. Yuma Area Critical Outages

The critical single contingency affecting the determination of the transmission import limit for the Yuma area is the loss of either the existing North Gila 500/69 kV transformer or the North Gila 69 kV bus. At North Gila, the 500/69 kV transformer consists of three single-phase units rated at 240 MVA and is connected through a 500kV ring bus to the Hassayampa-North Gila 500 kV line and the North Gila-Imperial Valley 500 kV line. The loss of the 69 kV bus at North Gila is possible, because it is configured as a main-and-transfer bus with no sectionalizing breaker.

The loss of either the North Gila 500/69 kV transformer or the 69 kV bus overloads the IID 161 kV line between the Pilot Knob substation and the Yucca substation during low generation conditions. In moderate generation conditions, the overload occurs on the 32nd Street-Ivalon 69 kV line. The emergency rating of the Pilot Knob-Yucca 161 kV line is 477 amps.

C. Yuma Area - SIL for 2003, 2004 and 2005

With planned system additions for the Yuma area, along with some accelerated projects (see Table 2), the SIL for the Yuma area will stay roughly constant at 164 MW for 2003, 2004 and 2005. Results of these studies are shown in Figures 6 through 8.

Figure 6

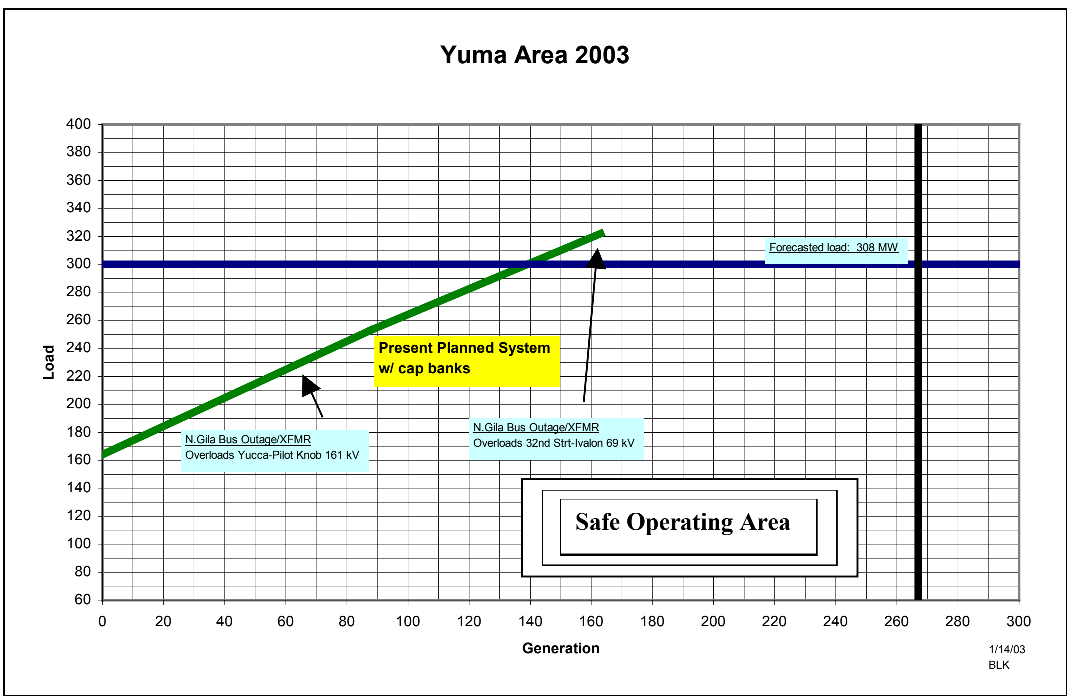


Figure 7

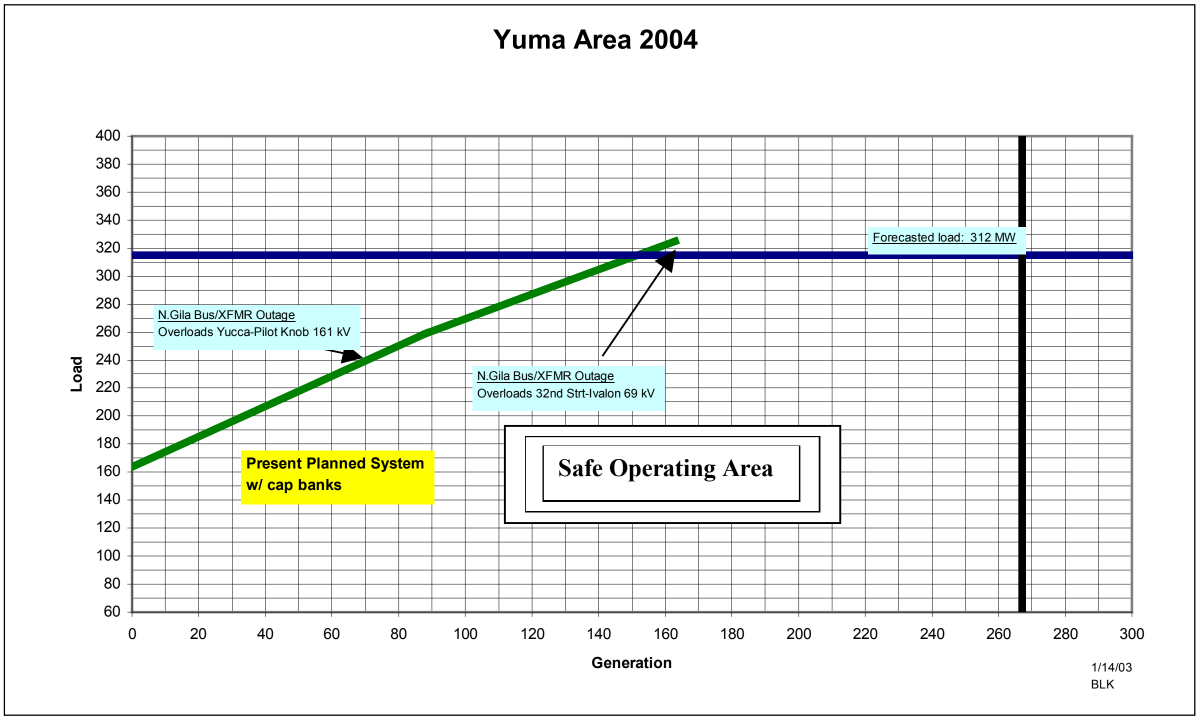
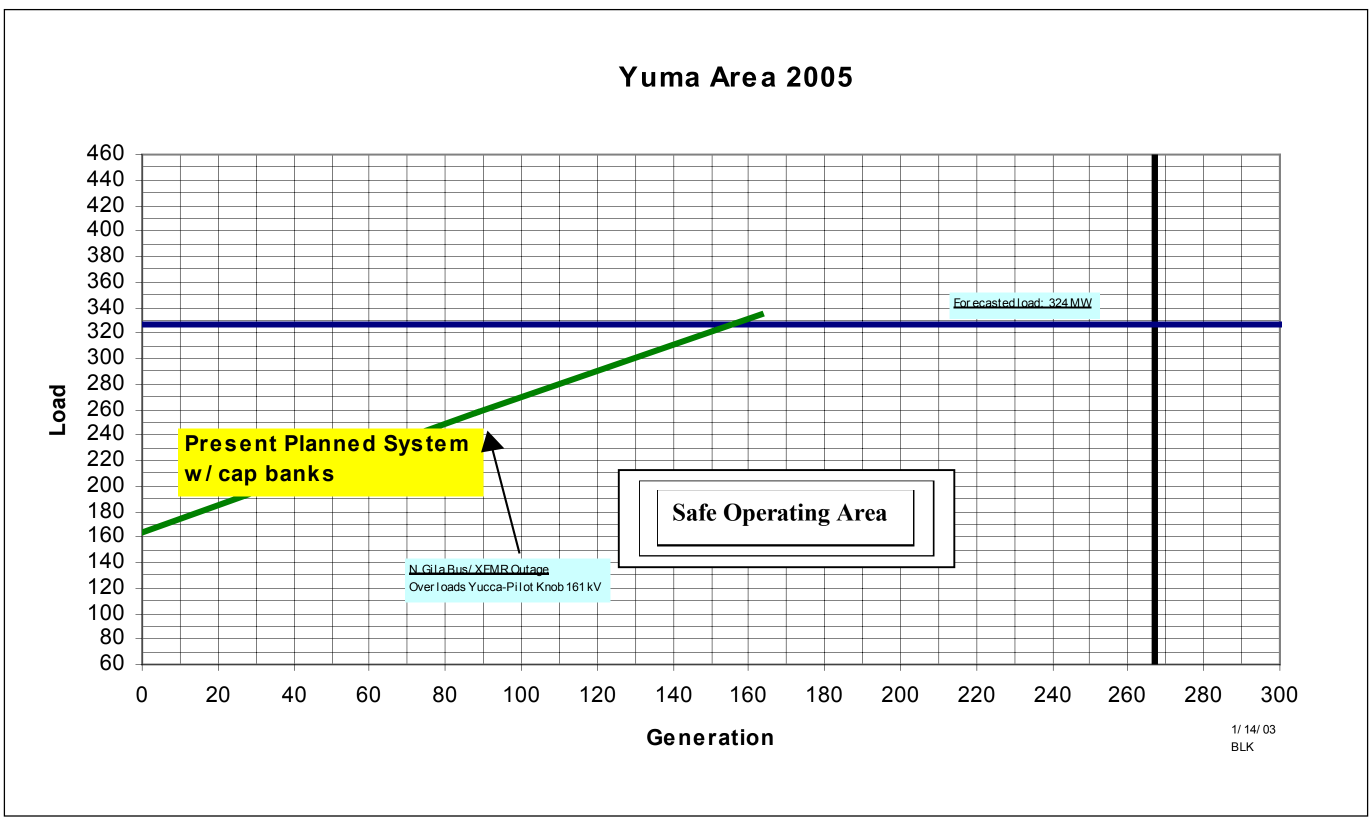


Figure 8



Also, the load listed along the vertical axis is the sum of the six 69 kV lines measured at their metering points in Figure 5, in addition to the YCA generation. In performing this analysis all planned projects were included in the model and several planned shunt capacitor banks were accelerated to maximize the capability of the transmission system by ensuing that the area was not voltage limited. These projects are listed in Table 4.

Table 4
Yuma Projects

Study Case	Case Description	
	System	Projects Added
2003 base case	Existing	Yucca-Cocopah 69kV re-conductor (planned 2003) Foothills 69kV, 32Mvar cap bank (advanced from 2006)
2004 base case	2003 base case	Riverside-10th Street 69kV re-conductor (planned 2004)
2005 base case	2004 base case	Yucca-Laguna 69kV re-conductor (planned 2005) Laguna 69kV, 28.8Mvar cap bank (planned 2005) 32nd Street 69kV, 32Mvar cap bank (advanced from 2006)
2005 sensitivity case	2005 base case	2nd North Gila 500/69kV, 240MVA transformer including addition of a 69kV bus section breaker (new) Foothills-Foothills tap 69kV re-conductor (advanced from 2007) 32nd Street-Ivalon 69kV re-conductor (advanced from 2006)

D. Generation Sensitivities

All generators in the Yuma Area are either connected to the Yucca 69 kV bus or very close to the Yucca 69 kV bus (YCA cogeneration) on the west side of Yuma. Because the critical outage results in a thermal overload on the west side of Yuma, these generators have equal impact on the import limit in the Yuma Area.

V. Analysis of RMR Conditions

A. Phoenix Area

1. Annual RMR Conditions

An RMR condition exists when the local load is greater than the SIL. In such cases, the RMR condition is the amount of generation that must be located inside of the constrained load area to meet the utility's peak load. RMR conditions for APS' Phoenix area, as well as the combined APS and SRP Phoenix area, are shown in Table 5 and are represented in a load-duration curve in Figure 9.

Table 5

Phoenix RMR Conditions Without Valley Generation
MW

	APS			Phoenix Total		
	2003	2004	2005	2003	2004	2005
Peak Load	4,519	4,777	4,957	9,843	10,339	10,711
Reduction for Raceway/Gavilan Peak	(63)	(163)	(224)	(63)	(163)	(224)
Load	4,456	4,614	4,733	9,780	10,176	10,487
Generation	-	-	-	-	-	-
Reserves	-	-	-	-	-	-
Net Valley Generation	-	-	-	-	-	-
Import Capability	3,621	3,658	3,709	8,557	8,632	8,733
Net Gen + Import	3,621	3,658	3,709	8,557	8,632	8,733
Must-Run Generation	835	956	1,024	1,223	1,544	1,754
Hours Load Exceeds Gen + Imp	518	590	656	326	436	536
Energy - GWH	170	211	243	170	246	334
Energy Percent of Valley Load	0.9%	1.0%	1.1%	0.4%	0.5%	0.7%

Figure 9

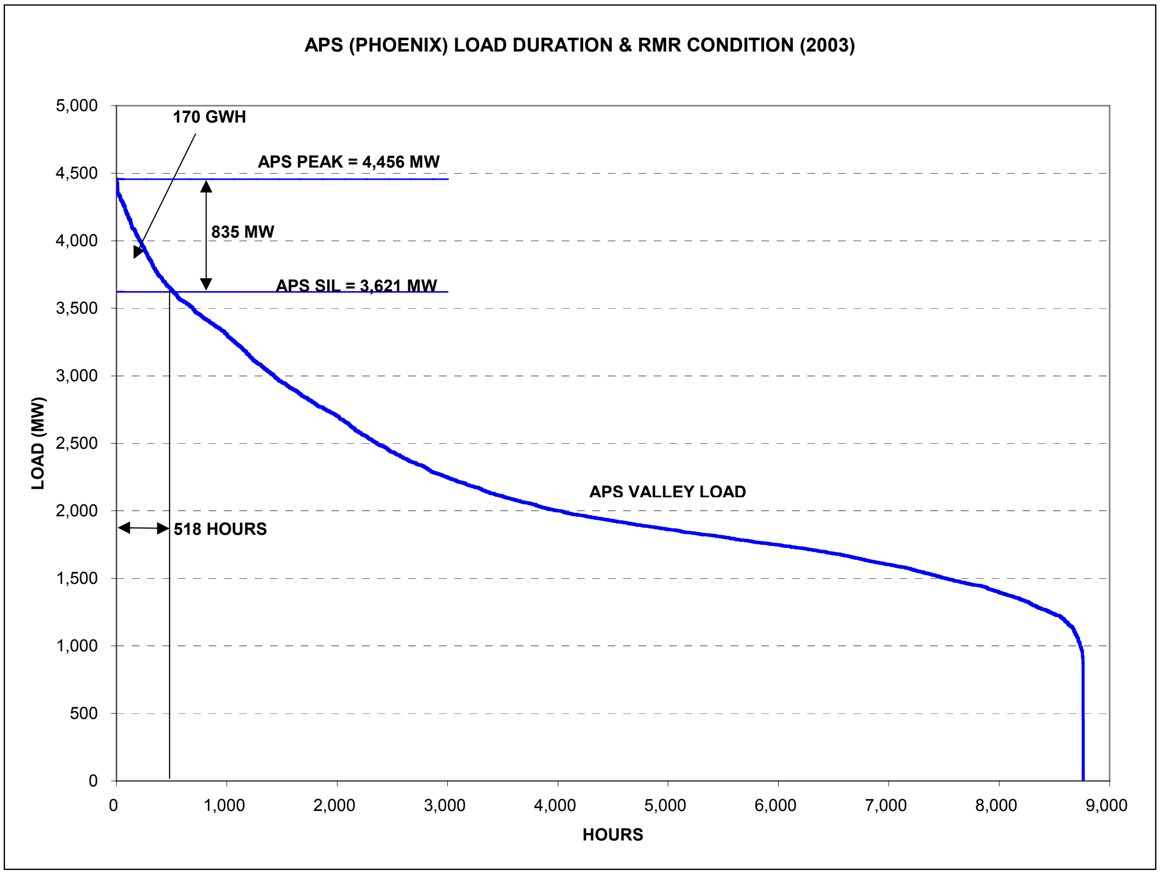


Table 5 shows that APS is expected to require from 835 MW to 1,024 MW of local generation resources over and above its import capability to meet peak load. These resources can be APS-owned local generation or non-APS owned generation located inside the Phoenix-area constraint, or transmission available from another owner (SRP) that can deliver within the constraint. For Phoenix, APS' generation is estimated to be in a must-run condition for between 518 to 656 hours per year. However, because RMR occurs only at peak, the amount of associated energy is only approximately one percent of APS' total Phoenix-area energy requirements, as shown in Figure 9 above.

The combined APS and SRP Phoenix-area system requires from 1,223 to 1,754 MW of resources, over and above transmission import capability, to meet the combined peak load.

2. *Maximum Load Serving Capability (MLSC)*

MLSC is the maximum load that can be reliably served in the load pocket. It is the import capability plus the generation capability located inside the load pocket, minus a reserve margin allowance for generation reliability. Based on the load forecast and SIL presented in this analysis, and existing and planned local generation, the following MLSCs for APS and Phoenix were developed. The approach used also shows how much generation or transmission may be needed to reliably meet load.

These results along with the generation and transmission assumptions are depicted in Table 6A for APS. Note that the table does not include West Phoenix generation owned by PWEC or Phoenix-area generation owned by SRP. As shown on this table, non-APS generation ranges from 365 MW to 554 MW to serve APS' Phoenix-area load reliably. The energy associated with this capacity need is very small — 23 to 55 GWH.

Table 6A

Non APS/UDC Must-Run Generation To Meet APS Phoenix-Area Load (MW)

	APS		
	2003	2004	2005
Peak Load	4,519	4,777	4,957
Reduction for Raceway/Gavilan Peak	(63)	(163)	(224)
Load	4,456	4,614	4,733
APS Generation	660	660	660
Reserves	(190)	(190)	(190)
Net Phoenix-area APS Generation	470	470	470
Import Capability	3,621	3,658	3,709
Net Gen + Import	4,091	4,128	4,179
Non APS/UDC Gen Required	365	486	554
Hours Load Exceeds Gen + Import	152	200	230
Energy – GWH	23	42	55
Energy Percent of Phoenix-area Load	0.1	0.2	0.3

Similar data for the entire Phoenix area is shown in Table 6B. This table shows generation ownership in the Phoenix area by PWEC and SRP and transmission import capability of SRP. Table 6B shows that Phoenix-area loads can be served reliably with Phoenix-area generation owned by APS, SRP and PWEC.

Table 6B

Non APS/UDC Must-Run Generation To Meet Phoenix-Area Load (MW)

	Phoenix Total		
	2003	2004	2005
Peak Load	9,843	10,339	10,711
Reduction for Raceway/Gavilan Peak	(63)	(163)	(224)
Load	9,780	10,176	10,487
Generation	2,822	2,822	3,647
Reserves	(503)	(503)	(866)
Net Phoenix-area Generation	2,319	2,319	2,784
Import Capability	8,557	8,632	8,733
Net Gen + Import	10,876	10,951	11,514
Non APS/UDC Gen Required	(1,096)	(775)	(1,027)
Hours Load Exceeds Gen + Import	---	---	---
Energy – GWH	---	---	---
Energy Percent of Phoenix-area Load	0.0	0.0	0.0

3. Area Load Forecast

APS' actual peak load within the Phoenix-area constraint is shown in Table 7 for 1999-2002, along with projected peak load for 2003-2005. Projected peak load is based on the same assumptions embodied in APS' total system load forecast used for budgeting and planning. This peak load is the load measured just inside the defined Phoenix-area constraint. The peak load is net of EHV transmission losses of about 3.8 percent, and before losses incurred on the 230 kV and distribution systems.

Table 7

Phoenix and Yuma Load and Energy

(MW / GWH)

	HISTORICAL				FORECAST		
	1999	2000	2001	2002	2003	2004	2005
APS SYSTEM							
LOAD	4,919	5,479	5,687	5,502	5,723	6,023	6,269
ENERGY	23,749	25,186	25,765	25,549	26,494	27,841	28,999
LF	55.1%	52.3%	51.7%	53.0%	52.8%	52.6%	52.8%
APS VALLEY							
LOAD	3,384	3,886	4,219	4,206	4,519	4,777	4,957
ENERGY	14,369	16,597	17,134	18,004	19,397	20,561	21,277
LF	48.5%	48.6%	46.4%	48.9%	49.0%	49.0%	49.0%
APS YUMA							
LOAD	270	273	296	292	308	312	324
ENERGY	1,197	1,262	1,326	1,341	1,395	1,439	1,472
LF	50.6%	52.6%	51.1%	52.4%	51.8%	52.5%	51.8%
PHOENIX							
LOAD					9,843	10,339	10,711
ENERGY					45,278	47,319	48,958
LF					52.5%	52.1%	52.2%

APS Phoenix-area load represents about 80 percent of APS' total system load. The Phoenix area has historically had about a 49 percent load factor. Hourly loads were shaped based upon APS' 2000 actual hourly loads for the Phoenix area. The load forecast for the combined APS/SRP Phoenix-area system was based on load forecast information provided to the WECC by other utilities, with adjustments made for load inside versus outside the Phoenix area, and again shaped according to year 2000 actual hourly loads. Year 2000 actual shapes were used in all regional load modeling to maintain the appropriate relationship of diversity between utilities and load areas. Even within the Phoenix area, the peak load of one utility has a small amount of diversity with others.

In 2003, APS' Raceway substation, which serves the far north side of Phoenix, will be connected to WAPA's Westwing-Raceway 230kV line. In 2004, APS' Gavilan Peak substation will also be tied into WAPA's system via the Pinnacle Peak-Prescott 230kV line. After tying into these WAPA lines, service to these substations will not use APS import capability. Accordingly, these loads are subtracted from APS Phoenix-area loads.

4. Generation

There are currently three owners of generation electrically located inside the Phoenix area — APS with 660 MW, SRP with 1,520 MW, and PWEC with 642 MW. Load serving entities (i.e., APS and SRP) own a combined total of 2,180 MW of local generation that is currently in service. Table 8 shows operational data associated with each unit.

Table 8

PHOENIX AREA GENERATION

OPERATOR	PLANT	TYPE	SUMMER CAPABILITY	MINIMUM LOAD	MINIMUM UP TIME	MINIMUM DOWN TIME	FOR	EFOR	FUEL TYPE
APS	Ocotillo 1	ST	110	30	8	8	4%	6%	NG
APS	Ocotillo 2	ST	110	30	8	8	4%	6%	NG
APS	Ocotillo GT1	GT	50	4	1	2	10%	11%	NG
APS	Ocotillo GT2	GT	50	4	1	2	10%	11%	NG
APS	West Phoenix GT1	GT	50	4	1	2	10%	11%	NG
APS	West Phoenix GT2	GT	50	4	1	2	10%	11%	NG
APS	West Phoenix CC1	CC	80	30	3	8	3.5%	6%	NG
APS	West Phoenix CC2	CC	80	30	3	8	3.5%	6%	NG
APS	West Phoenix CC3	CC	80	30	3	8	3.5%	6%	NG
APS SUBTOTAL			660						
SRP	Agua Fria 1	ST	113	57	8	8	4%	6%	NG
SRP	Agua Fria 2	ST	113	57	8	8	4%	6%	NG
SRP	Agua Fria 3	ST	181	92	8	8	4%	6%	NG
SRP	Agua Fria 4	GT	73	35	1	2	10%	11%	NG
SRP	Agua Fria 5	GT	73	32	1	2	10%	11%	NG
SRP	Agua Fria 6	GT	70	32	1	2	10%	11%	NG
SRP	Crosscut HY1	HY	3	N/A	N/A	N/A	0%	0%	WAT
SRP	Kyrene 1	ST	34	14	8	8	4%	6%	NG
SRP	Kyrene 2	ST	72	29	8	8	4%	6%	NG
SRP	Kyrene GT4	GT	59	25	1	2	10%	11%	NG
SRP	Kyrene GT5	GT	53	24	1	2	10%	11%	NG
SRP	Kyrene GT6	GT	53	24	1	2	10%	11%	NG
SRP	Kyrene CC1	CC	250	161	3	4	8%	9%	NG
SRP	Santan 1	CC	92	35	3	8	3.5%	6%	NG
SRP	Santan 2	CC	92	35	3	8	3.5%	6%	NG
SRP	Santan 3	CC	92	36	3	8	3.5%	6%	NG
SRP	Santan 4	CC	92	35	3	8	3.5%	6%	NG
SRP	Santan 5	CC	275	165	3	4	8%	9%	NG
SRP	Santan 6	CC	550	330	3	4	8%	9%	NG
SRP	South Consolidated 1	HY	1						WAT
SRP	Transport GT1	GT	4						NG
SRP SUBTOTAL			2,345						
PWEC	West Phoenix CC4	CC	112	84			3.5%	6%	NG
PWEC	West Phoenix CC5	CC	530	178			8%	9%	NG
PWEC SUBTOTAL			642						
VALLEY TOTAL			3,647						

APS owns West Phoenix CC 1-2-3, West Phoenix CT 1-2, Ocotillo ST 1-2, and Ocotillo CT 1-2. These units collectively have a 660 MW summer rating. These units have historically operated at capacity factors in the 3-30 percent range, and are expected to operate at lower capacity factors for the next few years as new high-efficiency plants come on line in Arizona and the Southwest. West Phoenix steam units 4, 5 and 6 are on cold standby and were not included in the study.

SRP owns the Agua Fria, Kyrene and Santan generating stations inside the Phoenix area, totaling 1,520 MW of generation. These units were mostly built in the late 1950s to the mid-1970s. The new Kyrene CC unit went into service in 2002. SRP has received a Certificate of Environmental Compatibility to construct another 825 MW of combined-cycle generation at the Santan plant. For this study, it is assumed the new Santan units will go into service in 2005.

PWEC has constructed West Phoenix CC 4 (112 MW), which went into service in June 2001, and is constructing West Phoenix CC 5 (530 MW), which expected to be on line by the summer of 2003. These units will improve reliability to the Phoenix area.

5. Reserves

Reliability within a load pocket such as Phoenix must be evaluated differently than for an unconstrained system. For example, although a 15 percent reserve margin or a largest hazard margin may be adequate for unconstrained total system loads, it does not provide adequate reliability to load pockets that cannot access all reserves present in the WECC interconnected system. APS performs an analysis that considers the size, forced outage rate, and effective forced outage rate of each unit in the load pocket to determine the probability that enough generation will be available when needed.

This analysis results in a reserve requirement of 190 MW for APS' Phoenix generating units. Specifically, the reserve analysis considers 470 MW of APS local generation as effectively firm (i.e., 660 MW minus 190 MW).

The reserve values are used in calculating the load serving capability for the APS-Phoenix and for the total-Phoenix load areas. In addition, the loads used in this analysis are based on Phoenix experiencing average weather. If the Phoenix area has a hot summer, APS load would be higher than projected, and the gas turbine and combined-cycle units' output would be reduced due to the hotter weather.

B. Yuma Area

1. Annual RMR Conditions

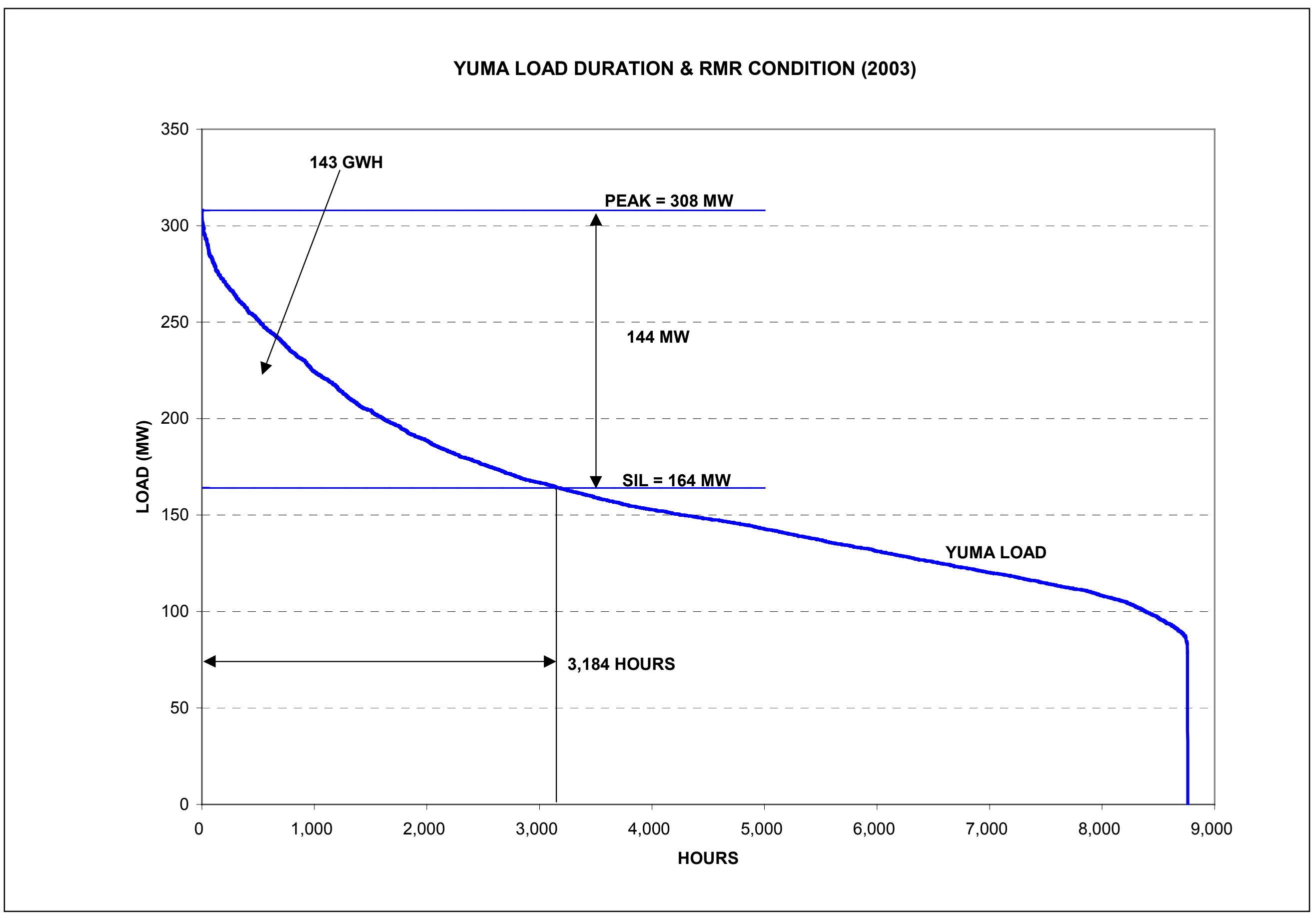
RMR conditions for the Yuma constrained area are shown in Table 9 and pictorially represented in a load-duration curve in Figure 10. Table 9 shows that APS requires from 144 MW to 160 MW of resources over and above its transmission import capability to meet peak load in Yuma. These resources can be APS-owned generation or non-APS owned generation located inside the constrained area. APS is in a must-run condition for between 3,184 to 3,834 hours per year in Yuma and the amount of associated energy is approximately 11.5 percent of APS' total Yuma energy requirement.

Table 9

Yuma RMR Conditions Without Generation
MW

	APS		
	2003	2004	2005
Load	308	312	324
Generation	-	-	-
Reserves	-	-	-
Net Generation	-	-	-
Import Capability	164	164	164
Net Gen + Import	164	164	164
Must-Run Generation	144	148	160
Hours Load Exceeds Gen + Imp	3,184	3,512	3,834
Energy - GWH	143	162	186
Energy Percent of Yuma Load	10.2	11.3	12.6

Figure 10



2. Maximum Load Serving Capability (MLSC)

Based on the load forecast and SIL presented in this report, and the 139 MW of APS local generation, the following MLSCs were developed. This approach also shows how much generation or transmission may be needed to reliably meet load. As shown in Table 10, from 2003 to 2005 APS could serve 233 MW of load without additional resources. With a load forecast of between 308 MW and 324 MW, APS will require from 75 MW to 91 MW of additional generation inside the load pocket. This resource need could be met from non-APS owned generation within the load pocket. Also, when the Yucca steam and YCA units are running, APS' requirement for generation inside the load pocket is reduced on a one-for-one basis. Approximately 21 GWH to 35 GWH of associated energy would be required.

Table 10

Non APS Must Run Generation To Meet Yuma Load
MW

	APS		
	2003	**2004**	**2005**
Load	308	312	324
Generation	139	139	139
Reserves	(70)	(70)	(70)
Net Yuma Generation	69	69	69
Import Capability	164	164	164
Net Gen + Import	233	233	233
Non APS Must Run Generation	75	79	91
Hours Load Exceeds Gen + Imp	836	962	1,104
Generation - GWH	21	27	34
Energy Percent of Yuma Load	1.5	1.8	2.3

3. Area Load Forecast

Table 7 shows APS' Yuma peak load for 1999-2002, and projected peak for 2003-2005. Projected peak is based on the same assumptions used in APS' total system load forecast used for budgeting and planning. This peak is the load measured just inside the Yuma area. It is net of EHV transmission losses of about 3.8 percent, and before losses incurred on the 69 kV and distribution systems. Yuma load represents approximately 5 percent of APS' total system load. Yuma has historically had a slightly higher load factor than that of the Phoenix area — 52 percent compared to 49 percent. Hourly loads were shaped using APS' Yuma actual hourly loads for 2000. Year 2000 actual shapes were used in all regional load modeling to maintain the appropriate relationship of diversity between utilities and load areas.

4. Generation

APS, IID and YCA own generation inside the Yuma load pocket. These plants have a summer capacity rating of 267 MW. Five of the six units run on natural gas while the other plant (Yucca CT 4) runs on oil. Additional power plant data for this generation is provided in Table 11. Of these plants, only the combustion turbines are owned by APS.

Although operated by APS, IID dispatches its steam plant to meet its load and spinning reserve needs. YCA is a cogeneration plant that has a contract with San Diego Gas & Electric (SDG&E). During summer 2002, APS purchased the output of this plant from SDG&E to serve the Yuma load area. Although APS has no dispatch rights to these units, whenever the units are running they provide internal generation in the Yuma area for purposes of using the import nomogram.

Table 11

YUMA-AREA GENERATION

OPERATOR	PLANT	TYPE	SUMMER CAPABILITY	MINIMUM LOAD	MINIMUM UP TIME	MINIMUM DOWN TIME	FOR	EFOR	FUEL TYPE
APS	Yucca GT1	GT	18	2	1	2	10%	10%	NG
APS	Yucca GT2	GT	18	2	1	2	10%	10%	NG
APS	Yucca GT3	GT	51	5	1	2	10%	10%	NG
APS	Yucca GT4	GT	52	5	1	2	10%	10%	FO2
APS SUBTOTAL			139						
IID	Yuma Axis 1	ST	75	18	8	8	4%	6%	NG
YCA	Yuma Cogen 1	CC	36	14	N/A	N/A	3.5%	6%	NG
YCA	Yuma Cogen 2	CC	17	7	N/A	N/A	3.5%	6%	NG
YCA SUBTOTAL			53						
YUMA TOTAL			267						

5. Reserves

Using a probabilistic generation analysis, the reserve margin for Yuma was calculated to be 70 MW.

VI. Economic Analysis of RMR

A. Introduction

To consider potential economic effects resulting from using local generation or arising from RMR conditions, an economic analysis was performed using a regional dispatch model. For this economic analysis, the production cost of meeting APS and SRP system loads was determined with the existing transmission import limitations in place. Next, a second hypothetical case was built in which the transmission import limits were removed. Comparing the two cases shows the economic costs of the transmission constraint.

These two cases were simulated with GE MAPS and their outputs were compared to determine the cost of transmission constraints. GE MAPS is a detailed regional production-costing model that includes the generation and transmission system of the entire WECC. In its dispatch, the model meets a company's load requirements by generating from the company's own units or buying available more economic generation from the market. The GE MAPS model also shows sales of economic generation to other utilities in the region subject to regional transmission constraints.

Much of the data used in modeling comes from public sources, however some of GE MAPS assumptions have been developed by APS. The GE MAPS database on existing generation was initially developed by several utilities in the West in the early 1990s to evaluate the economics of interregional transmission projects. It has been enhanced by the WECC in the mid-1990s and, like many other users of the model, APS continues to enhanced it to reflect system improvements and resources. This model includes all new generation expected to be built in the West, including the plants under construction or in operation near Hassayampa.

The transmission modeling in GE MAPS is based on the WECC's current power flow case for 2003, and includes the new Palo Verde-Rudd 500 kV transmission line. Transmission modeling of Yuma was enhanced by APS to accurately model the transmission constraints in that load pocket, based on APS' operational experience. The transmission model is an electrical flow model as opposed to a transport model. That means that transmission flows are subject to physical electrical constraints as well as scheduling constraints. Electrical constraints of the system are based on the WECC's path rating catalog, with additional local constraints such as the Phoenix import constraints. A description of GE MAPS (Appendix B) as well as some of its output is provided in Appendices C and D to this report.

The following items were quantified based on the GE MAPS simulations:

- Number of hours per year the Phoenix and Yuma area transmission system is expected to be constrained by the import limits;
- Phoenix and Yuma generation capacity factors;

- APS and SRP cost to serve their system, including fuel, variable O&M, purchase power cost and wholesale interchange sales margins; and
- Phoenix and Yuma generation emissions.

West Phoenix CC 4 and 5 and Santan CC 5 and 6 were included in the simulation. West Phoenix units were not assumed to be under the dispatch control of APS, though they may be selling to APS as may any of the other new generators. When the new West Phoenix combined cycles are operating, whether or not they are selling to APS, they mitigate must-run conditions in the Phoenix area because the plants are electrically located inside the Phoenix-area constraint. Thus, if these units are scheduled outside the Phoenix area, a like-amount of power can be counter-scheduled back into the Phoenix area without affecting the transmission import limits. Due to the high efficiency of new combined cycle units, it is anticipated that older existing generation within the Phoenix area will operate less than it has historically. This older existing generation, however, remains particularly valuable as inexpensive capacity reserves.

B. Phoenix

1. Phoenix Imports

Transmission imports to APS and to the Phoenix load pocket are provided in Appendix C for the summers of 2003-2005. During non-summer months, transmission imports do not approach their limits. Additionally, actual import flows for the summer of 2002 are also shown for reference. However, when considering these power flows, note that the Palo Verde-Rudd 500 kV transmission line was not in service in 2002 but is assumed to be in service by summer 2003. Due to additional transmission import capacity from this new line, projected flows in 2003 through 2005 are higher than those shown in 2002. The chart does, however, confirm the pattern of flows produced by the GE MAPS model.

Table 12 shows that under economic dispatch conditions for APS Phoenix-area generation, APS could approach its transmission import limits for 32-174 hours per year, while total Phoenix imports would be limited between 0 and 30 hours per year. The addition of Santan 5 and 6 in 2005 would further relieve the import constraints into the Phoenix area. While the APS import would be limited to 174 hours, APS would be able to meet its load requirements primarily by running its Phoenix-area generation. During these hours, it would be more economical to import less expensive power generated either by APS-owned units outside the Phoenix area or purchased from the wholesale market. However, the amount of energy associated with re-dispatching as a result of the transmission constraint amounts to only 44 GWH in 2005 compared to APS' overall Phoenix-area energy requirements of approximately 21,000 GWH. This is approximately 0.2 percent of required energy.

Table 12

IMPACT OF ELIMINATING PHOENIX IMPORT LIMITS

	With Import Limits			Without Import Limits			Difference (Without minus With)		
Hours Limiting	**2003**	**2004**	**2005**	**2003**	**2004**	**2005**	**2003**	**2004**	**2005**
APS	32	146	174	0	0	0	(32)	(146)	(174)
Phoenix	4	30	0	0	0	0	(4)	(30)	0
Phx Plant Generation (GWH)									
APS	64	98	88	57	55	44	(7)	(43)	(44)
Phoenix	1,431	1,924	3,776	1,422	1,877	3,731	(9)	(47)	(45)
Phx Plant Capacity Factor (%)									
APS	1.1	1.7	1.5	1.0	1.0	0.8	-0.1	-0.7	-0.8
Phoenix	5.8	7.8	11.8	5.8	7.6	11.7	0.0	-0.2	-0.1
Cost of Constraints ($M)									
Valley Utilities Total							0.03	0.4	0.7

2. *Operation of Phoenix-Area Generating Units*

Historically the Phoenix area's combined-cycle power plant capacity factors have ranged from 3 to 48 percent, with an average of about 19 percent. Capacity factors for steam-fired plants ranged from 3 to 33 percent, averaging about 10 percent. Capacity factors for simple-cycle combustion turbines ranged 0 to 13 percent, averaging about 1-1/2 percent. Historical capacity factors are shown in the Table 13 for APS and SRP by plant type for the period 1991 to 2000.

Operation of these units in 1999-2001 was higher than the historical average because the Western Interconnection and the Phoenix area both experienced high price volatility, high load growth, and few new generation resources had been added since the 1980s. With new higher-efficiency power plants coming on line by 2003, as well as the presence of the new Palo Verde-Rudd 500 kV transmission line, the older Phoenix-area units are expected to run at lower capacity factors. As noted above, however, these units remain critical to maintaining Phoenix-area reliability.

Even if the Phoenix-area transmission import limits were totally eliminated, these older units would still be needed to economically meet summer peak loads. Elimination of the constraints only reduces the capacity factors of all Phoenix-area plants — including West Phoenix 4 and 5 and Santan 5 and 6 — by less than 1 percent. Removing the transmission constraint reduces local generation by less than 50 GWH per year. Table 12 summarizes the results of the simulation analysis.

Table 13

PHOENIX-AREA POWER PLANT HISTORICAL CAPACITY FACTOR (%)

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
APS										
STEAM	6.6	9.6	9.8	12.9	8.9	8.7	10.6	16.1	22.5	33.1
COMBINED CYCLE	18.2	23.2	29.6	32.4	28.5	22.7	18.8	27.0	33.9	47.8
COMBUSTION TURBINE	0.9	1.3	1.1	2.0	1.0	1.3	2.4	4.4	4.5	13.3
SRP[1,2]										
STEAM	5.8	7.4	5.1	3.5	5.3	5.9	5.5	7.3	20.7	23.6
COMBINED CYCLE	15.7	3.0	6.2	9.0	8.3	5.1	4.6	9.7	23.2	27.9
COMBUSTION TURBINE	0.7	0.1	0.3	0.3	0.0	0.1	0.2	0.4	1.6	2.0
TOTAL PHOENIX										
STEAM	6.1	8.0	6.6	6.3	6.4	6.7	7.1	10.0	21.2	26.5
COMBINED CYCLE	16.8	11.9	16.5	19.3	17.2	12.9	10.6	17.0	27.7	36.3
COMBUSTION TURBINE	0.7	0.5	0.6	0.9	0.4	0.5	1.0	1.8	2.6	5.8

3. *Cost Impacts*

An estimate of the cost of the transmission import constraints can be determined by comparing the system cost for APS and SRP to serve their customers with and without constraints. Costs included in the analysis are fuel, variable O&M, purchased power and wholesale sale margin credits. The results of this analysis showed no measurable savings in 2003 for APS or for the total Phoenix area to completely relieve the constraints. Potential savings in 2004 and 2005 averaged about $500,000 per year for the total Phoenix area or 0.1 percent of the combined production cost. See Table 12.

4. *Emissions Impact*

In addition to economic modeling, the GE MAPS analysis evaluated the change in plant air emissions that would result from removing the transmission constraint. Specifically, the emission impact to the Phoenix area from removing transmission constraints and "moving" generation outside the Phoenix area was calculated. Four criteria pollutants are routinely tracked for power plants: NO_X, CO, VOCs and PM_{10}. Maricopa County is a non-attainment area for CO, VOCs and PM_{10}. NO_X is a precursor for ozone and therefore is included.

The emissions impact from power plant emissions in the Phoenix area was estimated by using the average emission rates of APS Phoenix-area units along with the modeled change in energy production. Emissions were also estimated for the other non-APS Phoenix-area units. Changes in emissions resulting from entirely eliminating the transmission import constraint into Phoenix are shown in Table 14. For comparison purposes, total emissions in Maricopa County were estimated by Maricopa County Environmental Services Department for 1999. Their emissions estimates include all stationary point sources, area sources, non-road mobile sources and on-road mobile and biogenic sources. To put the results into perspective, changes in Phoenix-area power plant emissions are shown as a percentage of total Maricopa County emissions.

Table 14
Phoenix Area Air Emissions Reduction

Pollutant	Avg. Reduction (tons/year)	Reduction of Phoenix Area Emissions (% of total emissions from all sources)
VOC	1.0	0.001
NO_x	29.5	0.049
CO	5.5	0.002
PM_{10}	1.8	0.002[1]

[1]Reduction % is based on 1994 actual emissions.

Table 15 shows APS and Phoenix-area emissions by type.

Table 15

PHOENIX POWER PLANT EMISSIONS (TONS)

	With Import Limits			Without Import Limits			Difference (Without minus With)		
NOx	2003	2004	2005	2003	2004	2005	2003	2004	2005
APS	62.8	102.7	95.4	56.4	53.9	43.2	(6.5)	(48.8)	(52.2)
Phoenix	141.6	201.5	260.6	134.7	151.8	209.1	(6.9)	(49.7)	(51.5)
CO									
APS	5.5	14.1	13.6	4.8	5.7	3.7	(0.7)	(8.5)	(9.9)
Phoenix	33.2	49.0	82.3	32.4	40.2	72.5	(0.8)	(8.7)	(9.8)
PM_{10}									
APS	2.5	5.2	5.0	2.2	2.4	1.7	(0.3)	(2.9)	(3.2)
Phoenix	37.5	51.6	97.5	37.1	48.6	94.3	(0.4)	(3.0)	(3.2)
VOC									
APS	1.3	2.6	2.7	1.2	1.1	0.9	(0.1)	(1.5)	(1.8)
Phoenix	14.0	19.7	35.4	13.8	18.1	33.6	(0.2)	(1.6)	(1.8)

C. Yuma

1. Yuma Imports

Transmission imports to the Yuma load pocket are provided in Appendix D. Unlike the Phoenix area, these imports do approach their limits at various times throughout the year. These plots are included in Appendix D for the cases in which the limits were removed.

Table 16 shows that APS could approach its import limits for 974 to 1,196 hours per year. The energy associated with these hours amounts to 50 to 57 GWH. During these hours, it would have been more economical to import cheaper power either generated on APS own units outside the Yuma area or purchased from the wholesale market if the import limits were increased.

Table 16

IMPACT OF ELIMINATING YUMA IMPORT LIMITS

	With Import Limits			Without Import Limits			Difference (Without minus With)		
Hours Limiting	**2003**	**2004**	**2005**	**2003**	**2004**	**2005**	**2003**	**2004**	**2005**
APS/Yuma	1,066	974	1,196	0	0	0	(1,066)	(974)	(1,196)
Yuma Generation (GWH)									
APS	54	50	57	0	1	1	(54)	(49)	(56)
Yuma	86	103	118	32	55	62	(54)	(48)	(56)
Yuma Plant Capacity Factor (%)									
APS	4.4	4.1	4.7	0.0	0.2	0.1	-4.4	-3.9	-4.6
Yuma	4.9	8.1	9.3	4.9	8.1	9.3	0.0	0.0	0.0
Cost of Constraints ($M)									
APS							(1.5)	(1.3)	(1.5)

2. Operation of Yuma Units

Historically, the Yucca CTs have operated at capacity factors of between 0.5 up to 7.9 percent, as shown in Table 17. On average they are in the 1 to 2 percent range.

Table 17

YUMA POWER PLANTS HISTORICAL CAPACITY FACTOR
(%)

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
YUCCA										
CT1	0.2	0.9	0.3	0.6	0.4	0.4	1.1	1.5	1.4	5.0
CT2	0.1	1.1	0.4	0.4	0.5	0.4	1.2	1.5	1.4	6.9
CT3	1.7	4.9	1.5	1.4	1.0	1.4	2.8	3.6	3.5	12.2
CT4	0.0	0.2	0.0	0.2	0.0	0.2	0.2	0.7	0.3	4.8
Total Yucca	0.7	2.2	0.7	0.7	0.5	0.7	1.4	2.0	1.8	7.9
YUMA AXIS	13.5	9.4	18.4	15.9	15.3	33.3	45.2	45.4	53.7	41.3
TOTAL YUMA	5.0	4.6	6.7	5.9	5.5	11.7	16.2	16.7	19.3	19.2

3. Cost Impacts

The GE MAPS analysis indicates that the Yuma import limit will be constraining from 974 to 1196 hours per year. Totally relieving the constraints could save APS from \$1.3 to \$1.5 million per year. See Table 16.

4. Emission Impacts

The emission impact on the Yuma area due to a potential relieving of transmission constraints and "moving" generation outside of the Yuma area was determined by GE MAPS similarly to the Phoenix analysis. Unlike Phoenix, however, Yuma County is a non-attainment area for PM_{10} only. Impacts on power plant emissions in Yuma were estimated by using average emission rates of APS units along with the change in energy production. Emissions were also estimated for the other non-APS units. By entirely eliminating the import limits into Yuma, emissions produced by power plants located inside the Yuma load pocket would change as shown in Table 18.

Table 18

YUMA POWER PLANT EMISSIONS (TONS)
(Includes Yucca 1-4 and Yuma Axis)

	With Import Limits			Without Import Limits			Difference (Without minus With)		
	2003	2004	2005	2003	2004	2005	2003	2004	2005
NOx	189	186	203	24	43	48	(165)	(143)	(155)
CO	39	43	50	7	13	14	(32)	(30)	(36)
PM_{10}	9	10	11	2	4	4	(7)	(6)	(7)
VOC	10	9	11	0	1	1	(10)	(9)	(10)

VII. TRANSMISSION ALTERNATIVES TO MITIGATE RMR

A. Phoenix Area

Two transmission alternatives were evaluated as potential mitigation of RMR conditions for the Phoenix area. For comparison purposes, a cost-benefit analysis was performed on the 2005 case with no Phoenix area generation operating.

The first alternative is the addition of 600 Mvar of shunt compensation (e.g. a static var compensator-SVC) at Kyrene with associated remedial action scheme logic and switching equipment to automatically insert the capacitor portion of the SVC at a very high speed upon detection of a loss of the Jojoba-Kyrene 500kV line. This alternative mitigates the voltage instability limitation by adding a strong reactive source of 600 Mvars of shunt compensation into the Phoenix area at the location that has lost the voltage support from the Palo Verde/Hassayampa area. This alternative would increase import capacity by 452 MW for a generation cost savings of $720,000 in 2005. However, the SVC alternative would cost $16 million. The annualized cost associated with this investment is estimated to be $2.4 million.

The second alternative considered was to modify the existing transmission system by looping the Jojoba-Kyrene 500kV line into the Rudd 500kV substation. This alternative is limited by the Rudd 500/230 kV transformers reaching thermal overload for a Rudd-Kyrene 500 kV line outage. This alternative provides no increase in SIL and, in fact, lowers the SIL due to increased loading on Rudd 500/230 kV transformers.

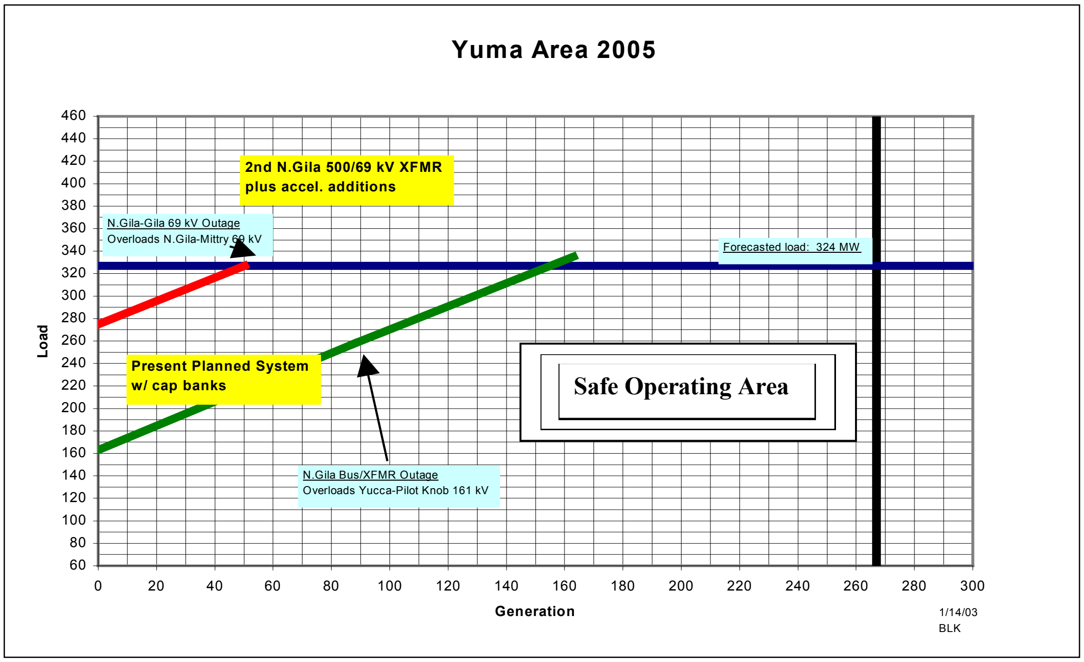
Neither of these alternatives is cost justified for the period covered by this study.

B. Yuma Area

For the 2005 timeframe, a second 500/69 kV 240 MVA transformer was added along with a 69 kV bus section breaker to the North Gila substation to evaluate the resultant increase in the SIL and MLSC for the Yuma area, and the resulting mitigation of RMR conditions. The cost of this project is estimated to be $3.5 million. With no local generation, completion of this project will increase the SIL by approximately 110 MW. Figure 11 shows the effect on the load serving capability (at or below the load forecast) of the Yuma area from adding the transformer.

This sensitivity case contains the same planned additions as in the 2005 base case (see Table 4) plus the addition of the re-conductoring of the 32nd Street-Ivalon 69 kV line and the Foothills-Foothills tap 69 kV line. These two additional projects are presently planned for 2006 and 2007, respectively, however both were advanced to maximize the effect of adding the second transformer.

Figure 11



With a cost of $3.5 million, the addition of the second N. Gila 500/69 kV transformer appears to be cost justified and will be further studied.

VIII. CONCLUSIONS

Phoenix Area Conclusions

1. During the summer, APS Phoenix-area load is expected to exceed the available transmission import capability for approximately 500 hours in 2003 and 650 hours in 2005. However, these hours represent only one percent of the annual energy requirements for APS' Phoenix area.

2. From a total Phoenix load, transmission, and resources viewpoint (APS, SRP, and PWEC), import limits are expected to cause APS local generation to be dispatched out of economic dispatch order for 32 hours in 2003, 146 hours in 2004, and 174 hours in 2005.

3. The estimated annual economic cost of Phoenix-area generation required to run out of economic dispatch order is estimated to be $720,000 in 2005, compared to a cost of approximately $16 million to relieve 452 MW of the Phoenix area's transmission constraint. Thus, the transmission alternative currently is not cost justified.

4. All Phoenix-area transmission and local generation are necessary to reliably serve all Phoenix-area peak load.

5. In capacity terms, APS will require from 365 MW in 2003 to 554 MW in 2005 of non-APS resources within the Phoenix area to serve the APS Phoenix-area load. These resources could be supplied from non-APS local generation (including PWEC West Phoenix Units 4 and 5, SRP Phoenix-area generation, or newly constructed local generation) or from remote generation delivered to APS using SRP Phoenix-area import capability.

6. Non-APS generation outside of the Phoenix load area (or inside the Phoenix load area when serving load outside) has the following impact on Phoenix-area import capability, measured as a percent of additional MW of import capability to MW of output:

   West Phoenix Units 4 and 5……………………134%

   Sundance……………………………………… 35%

   Desert Basin…………………………………… 24%

   Hassayampa Area……………………………… 0%

   Panda Gila River………………………………. 0%

7. Removing the transmission constraint would reduce total Phoenix-area air emissions by the following average annual amounts over the 2003-2005 period.

Table C1
Phoenix Area Air Emissions Reduction

Pollutant	Avg. Reduction (tons/year)	Reduction of Phoenix Area Emissions (% of total emissions from all sources)
VOC	1.0	0.001
NO_x	29.5	0.049
CO	5.5	0.002
PM_{10}	1.8	0.002

8. Removing the import restriction into the Phoenix area reduces the APS local generation capacity factor from 1.4% to 0.9%.

Yuma Area Conclusions

9. The Yuma-area load is expected to exceed the available transmission import capability for approximately 3,200 hours in 2003 and 3,800 hours in 2005, although the amount of total load in the Yuma area is only approximately 300 MW.

10. From a total Yuma load, transmission, and resources viewpoint (APS, IID, and YCA), the import constraint could cause APS Yuma generation to be dispatched out of economic dispatch order for approximately 1,070 hours in 2003, 975 hours in 2004, and 1,200 hours in 2005.

11. The addition of a second 500/69 kV transformer at the North Gila station in the Yuma area will be further studied. Preliminary analysis shows that installation of this transformer significantly reduces Yuma-area RMR. Preliminary study results show potential savings in energy costs of approximately $1.4 million per year for the years 2003 through 2005. The cost to install a second 500/69kV transformer is estimated to be $3.5 million.

12. All existing Yuma-area transmission and generation resources are necessary to reliably serve the Yuma-area load.

13. In capacity terms, APS will require from 75 MW in 2003 to 91 MW in 2005 of non-APS resources in the Yuma area to serve the APS Yuma-area load. These resources may be supplied from the 75 MW IID steam generator at the Yucca substation, the 53 MW YCA co-generator near the Riverside substation, or future generation/transmission construction in the Yuma area.

14. Removing the transmission constraint could reduce total Yuma-area air emissions by the following average annual amounts for the period 2003-2005.

Table C2
Yuma Area Air Emissions Reduction

Pollutant	Avg. Reduction (tons/year)	Reduction of Yuma Area Emissions (% of total emissions from all sources)
VOC	9.5	Unavailable
NO_x	154	Unavailable
CO	33	Unavailable
PM_{10}	6.5	0.003

15. Removing the import restriction into the Yuma area could reduce the APS Yuma generation capacity factor from 4.4 percent to 0.1 percent.